Experimental and Theoretical Investigation of Methane-Gas-Hydrate Dissociation in Porous Media

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Summary. Vast quantities of natural gas deposits exist in the form of solid hydrates. Methane gas hydrate was formed and dissociated for the first time in Berea core samples. A three-phase 1D model was developed to simulate the process of gas production from Berea sandstone samples containing methane hydrate by means of a depressurization mechanism. The model closely matched the experimental data of gas and water production, the progress of the dissociation front, and the pressure and saturation profiles.

Introduction

Natural-gas hydrates are crystalline, ice-like substances belonging to a class of compounds called clathrates. These chemical compounds have natural-gas molecules bound within almost spherical water cages through physical rather than chemical bonds. Two natural-gas-hydrate crystal structures result from the combination of these water cages. The crystal properties of both structures have been reviewed in detail. When all cavities of either structure are occupied, there are about 15 gas molecules per 85 water molecules.

Depressurization, on the other hand, has been the method used in the single example of hydrate production from the Mississippi delta in the U.S.A. Herd and Angert proposed an isothermal depressurization model in which heat was assumed to flow instantaneously from the surroundings to the hydrate body. Holder and Angert proposed a methane-hydrate global depressurization model in which the heat of dissociation came from the sensible heat of the reservoir itself. Burshears extended this model to gas mixtures. Yousif et al. proposed a model similar to the Russian moving-boundary model, but allowed for a temperature gradient within the hydrated zone; this model, which has had some limited experimental confirmation, shows the inverse relationship of production with time, relative to the work of Verigin et al.

In all the models proposed to date, the flow equations in a hydrate zone were not considered as a complement to the equations of mass and energy. One purpose of this work was to model the hydrate-dissociation process considering equations of change for both mass and momentum for each of the three phases present (gas, water, and hydrate) in the porous medium. It was our purpose to provide experimental measurements of slow, isothermal hydrate dissociation in porous media for confirmation or refinement of the model.

Depressurization Model

Consider a porous medium of uniform porosity occupying the region \(0 < x < L\). Initially, hydrate, water, and gas are at uniform pressure, \(p^0\), and temperature, \(T^0\). At time \(t=0\), the pressure at the boundary \(x=0\) is lowered to a new pressure that is less than the equilibrium pressure, \(p_e\), and is held constant thereafter. Hydrate dissociation begins; pressure and saturation distributions develop throughout the system. Water and gas flow through the system because of the resultant pressure gradient and are produced at the boundary \(x=0\).

For simplicity, we assume that the depressurization process is carried out under isothermal conditions. Such an assumption is valid only if the boundary pressure is not far enough below the equilibrium pressure to ensure slow dissociation. With this restriction, the transport equations governing hydrate dissociation and the flow of gas and water through the porous medium are:

\[
\frac{\partial (\rho_g V_g)}{\partial x} + \frac{\partial m_g}{\partial t} = \frac{\partial (\rho_g S_g)}{\partial t}, \quad (1)
\]

\[
\frac{\partial (\rho_w V_w)}{\partial x} + \frac{\partial m_w}{\partial t} = \frac{\partial (\rho_w S_w)}{\partial t}, \quad (2)
\]

and

\[
\frac{\partial m_H}{\partial t} = \frac{\partial (\rho_H S_H)}{\partial t}. \quad (3)
\]

The quantity \(-m_H\) in Eq. 3 represents the local mass rate of hydrate dissociated per unit volume as a result of depressurization. The quantities \(m_g\) and \(m_w\) in Eqs. 1 and 2 represent the corresponding local mass rate of gas and water produced per unit volume, respectively. These are related by:

\[
m_H = m_g + m_w \quad \text{(4)}
\]

\[
m_g = m_H \frac{M_g}{N_H M_w + M_g} \quad \text{(5)}
\]

The local gas-generation rate caused by hydrate dissociation may be obtained from the Kim-Bishnoi model:

\[
m_g = k_d A_s (p_e - p) \quad \text{(6)}
\]

During the dissociation process, the volume occupied by the gas and water continuously increases with time as a result of depletion of the hydrate phase. Accordingly, the PV occupied gas and water and the permeability of the porous medium will be changing continuously with time. Let \(w_g\) denote the PV occupied by water and gas per unit volume of porous medium. Assuming that the hydrate phase forms a continuous film coating the interior of the solid surface of the porous medium, we may use the parallel-cylinder model to obtain the following relationship for the specific surface area occupied by water and gas:

\[
A_s = \left(\frac{\phi_{\text{avg}}}{2k}\right)^{1/4} \quad \text{(7)}
\]
where \( \phi_{wg} \) and \( k \) change with time. An empirical relationship between \( k \) and \( \phi_{wg} \) was obtained from field data of a Berea sandstone reservoir, \(^{13}\) as shown in Fig. 1.

Introducing Darcy's law \( [v_x = -(k \mu R/\mu) \partial p/\partial x] \) into Eqs. 1 through 3, we obtain

\[
\frac{\partial}{\partial x} \left( \rho_w k \mu R \frac{\partial p}{\partial x} \right) + \dot{m}_w = \frac{\partial}{\partial t} (\phi_p S_w), \quad (8)
\]

\[
\frac{\partial}{\partial x} \left( \rho_g k \mu R \frac{\partial p}{\partial x} \right) + \dot{m}_g = \frac{\partial}{\partial t} (\phi_p S_g), \quad (9)
\]

and \(-\dot{m}_H = \frac{\partial}{\partial t} (\phi_p S_H). \quad (10)\)

In addition, the following auxiliary equations close the system:

\[
S_g + S_w + S_H = 1 \quad (11)
\]

and \( P_c(S_w) = P_g - P_w. \quad (12)\)

The capillary pressure and the relative permeability relationships for Berea sandstone shown in Fig. 2 were taken from Amyx et al. \(^{13}\) Note that these relationships depend on the porosity, permeability, and pore-size distribution of the medium. Thus, as \( \phi_{wg} \) and \( k \) change with time, we expect \( P_c(S_w) \) and \( k_r(S_w) \) to change accordingly. As discussed later, however, the change was found to have a marginal effect on the changes of porosity and permeability in a porous medium containing hydrates during dissociation.

Eqs. 8 through 12 constitute a system of equations for the five unknowns \( P_g, P_w, S_g, S_w, \) and \( S_H. \) The initial and boundary conditions are given below.

**Initial conditions (\( t = 0 \) and \( 0 \leq x \leq L \)).**

\[
p = p_0, \quad (13a)
\]

\[
S_H = S_H^0, \quad (13b)
\]

\[
S_w = S_w^0, \quad (13c)
\]

and \( S_g = S_g^0. \quad (13d)\)

**Boundary conditions.**

\[
p(0,t) = p_0 \text{ at } x = 0 \text{ for } t \geq 0 \quad (14a)
\]

and \( \partial p(L,t)/\partial x = 0 \text{ at } x = L \text{ for } t \geq 0. \quad (14b)\)

Numerical Solution

No analytical solution is available for the system given by Eqs. 8 through 12; therefore, a numerical solution was considered. Numerical approximation of the space and time derivatives was considered, which resulted in a set of simultaneous nonlinear finite-difference equations. This set of equations was linearized; the solution was obtained with an iterative method.

The space and time derivatives of the equations were approximated by a block-centered finite-difference scheme. The central-difference approximation was used for the spatial derivatives; a forward difference was used for the time derivatives. This method gives

\[
\frac{1}{\Delta x} \frac{\partial}{\partial x} \left( \frac{\rho_w k \mu R}{\mu} \frac{\partial p}{\partial x} \right) + \dot{m}_w = \frac{\partial}{\partial t} (\phi_p S_w), \quad (15)
\]

\[
\frac{1}{\Delta x} \frac{\partial}{\partial x} \left( \frac{\rho_g k \mu R}{\mu} \frac{\partial p}{\partial x} \right) + \dot{m}_g = \frac{\partial}{\partial t} (\phi_p S_g), \quad (16)
\]

and \(-\dot{m}_H = \frac{\partial}{\partial t} (\phi_p S_H). \quad (17)\)

where \( \delta_x \) is the central-difference operator defined by \( \delta_x f = f(x + \Delta x/2) - f(x - \Delta x/2) \) and \( \delta_t \) is the forward-difference operator defined by \( \delta_t f = f(t + \Delta t) - f(t). \)

According to the block diagram in Fig. 3, Eqs. 15 through 17 may be discretized as

\[
\frac{1}{\Delta x} \left( \frac{\rho_w k \mu R}{\mu} \right) \frac{p_{s_i+1} - p_{s_i}}{\Delta x} - \frac{1}{\Delta t} \left( \frac{\rho_g k \mu R}{\mu} \right) \frac{p_{s_i} - p_{s_{i-1}}}{\Delta t} + \dot{m}_{s_i} = \frac{1}{\Delta t} \left[ (\phi_p S_g)^n + 1 - (\phi_p S_g)^n \right], \quad (18)
\]

\[
\frac{1}{\Delta x} \left( \frac{\rho_w k \mu R}{\mu} \right) \frac{p_{g_i+1} - p_{g_i}}{\Delta x} - \frac{1}{\Delta t} \left( \frac{\rho_g k \mu R}{\mu} \right) \frac{p_{g_i} - p_{g_{i-1}}}{\Delta t} + \dot{m}_{g_i} = \frac{1}{\Delta t} \left[ (\phi_p S_g)^n + 1 - (\phi_p S_g)^n \right], \quad (19)
\]

and \(-\dot{m}_{H_i} = \frac{1}{\Delta t} \left[ (\phi_p S_H)^n + 1 - (\phi_p S_H)^n \right]. \quad (20)\)

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Inserting the auxiliary Eqs. 11 and 12 into Eq. 18 through 20 gives the following set of equations for \( p_g, S_w, \) and \( S_H \):

\[
\frac{1}{\Delta x} \left( \frac{\rho_g k_{rg}}{\mu_g \Delta x} \right) (p_{gi+1} - p_{gi}) - \frac{1}{\Delta x} \left( \frac{\rho_g k_{rg}}{\mu_g \Delta x} \right) (p_{gi} - p_{gi-1}) + m_{gi} = \frac{1}{\Delta t} \left\{ (\phi_i \rho_{gi} (1 - S_{wi} - S_{Hi}))^{n+1} - (\phi_i \rho_{gi} (1 - S_{wi} - S_{Hi}))^n \right\}, \tag{21}
\]

\[
\frac{1}{\Delta x} \left( \frac{\rho_g k_{rw}}{\mu_w \Delta x} \right) (p_{wi+1} - p_{ci+1} - p_{gi} + P_c i) - \frac{1}{\Delta x} \left( \frac{\rho_g k_{rw}}{\mu_w \Delta x} \right) (p_{ci} - p_{gi} - p_{gi-1} + P_{ci-1}) - m_{wi} = \frac{1}{\Delta t} \left\{ (\phi_i \rho_{wi} S_{wi})^{n+1} - (\phi_i \rho_{wi} S_{wi})^n \right\}, \tag{22}
\]

and

\[
- \frac{m_{Hi}}{\Delta t} = \frac{1}{\Delta t} \left\{ (\phi_i \rho_{Hi} S_{Hi})^{n+1} - (\phi_i \rho_{Hi} S_{Hi})^n \right\}. \tag{23}
\]

The central-difference representation given by these equations results in some coefficients that must be evaluated at the intercell boundaries. Arithmetic mean weighting is used to approximate the intercell values for \( \mu \) and \( \rho \), harmonic weighting is used for \( k \), and upstream weighting is used for \( k_r \). The initial and boundary conditions in discretized form are given below.

**Model Simulations**

Figs. 4 through 14 show typical results from the model. Table 1 lists the initial and the boundary conditions and the physical properties used for the results in these figures. The equilibrium pressure shown in Table 1 is that for methane hydrate.
Figs. 4 through 7 show the pressure and saturation distributions for \( t = 10, 50, \) and 85 minutes. It is clear from Fig. 4 that a sharp pressure front travels through the porous medium as dissociation proceeds. Ahead of the front, the saturations of the hydrate, gas, and water phases (shown in Figs. 5 through 7) are undisturbed at their initial values on the right of each figure. Behind the front (on the left in Figs. 4 through 7), the pressure is essentially uniform at the outlet pressure \( p_0 \). Within this region, hydrate dissociation is distributed throughout a zone controlled by kinetics and pressure drop.

In Fig. 5, the hydrate-dissociation interface is widely distributed over the core. The leading edge of the hydrate-dissociation interface is defined as the point at which \( S_H = S_{H0} \). At the time the trailing edge of the dissociation interface reaches zero (between 50 and 85 minutes), the leading edge is more than halfway through the length of the core.

Fig. 6 shows the gas-saturation distribution with time. The plot shows the gas evolution to be in a reverse S shape, initially undergoing a period of exponential growth before slowing again. The initial gas-saturation buildup is caused by the initial low absolute permeability when hydrates occupy a large portion of the pore space. Initially, the rate at which the gas is generated is much larger than can be accommodated by the available flow passage, causing the exponential buildup in the gas saturation shown in all the curves in Fig. 6. At later times, however, each gas-saturation curve shows an inflection point at the end of the exponential region. The inflection point results from the increase in both absolute permeability and relative permeability of gas as its saturation reaches about 57% (a water saturation of 43% on the relative permeability plot, Fig. 2). In Fig. 6, the 85-minute curve achieves the maximum value of 80% gas saturation, coexisting with the immobile water, which is at 20% saturation.
Both hydrate- and gas-saturation curves of Figs. 5 and 6 can be used to explain the water-saturation curves of Fig. 7. The gas evolves at the leading edge of the hydrate interface very rapidly. At the vicinity of the interface, the pressure drops sharply from the equilibrium pressure to the final pressure, causing substantial gas expansion. The rapid gas evolution expands to occupy most of the pore space, expelling the water produced during the dissociation process and thereby creating a water front. As shown in the water relative permeability curve of Fig. 2, at about 40% water saturation, the water front gains appreciable mobility and flows toward the outlet. This effect creates a localized maximum value of water saturation, as shown in Fig. 7. This behavior may be interpreted as a magnified solution-gas drive. The large gas front sweeps the water from the porous medium so that only the immobile water remains, in accordance with the large water production (up to 80%) indicated by Makogon in the Messoyakha field. This effect may indicate a significant production hindrance during the recovery of natural gas from hydrates.

Fig. 8 also indicates an increase in absolute permeability with time as hydrate dissociates. Fig. 9 shows the porosity increase with time as the hydrate dissociates to give more pore space. Both Figs. 8 and 9 are related to the hydrate-dissociation rate through the porosity/permeability relation shown in Fig. 1. While Patil et al. 15
have made a start at quantifying the relationship of permeability to porosity in hydrate cores, much more remains to be done.

Fig. 10 shows the linear position of the leading edge of the hydrate-dissociation front with time. This linear relationship should not be confused with our previous work, in which the dissociation front varies with the square root of time, as is characteristic of a moving-boundary problem. Figs. 11 and 12 show the cumulative gas and water production, respectively, as a function of time.

Experimental Work
Methane hydrate was formed and dissociated in Berea sandstone cores (15.2 cm long and 1.3 cm in diameter) with the apparatus shown in Fig. 13. The core sample used in this experiment had an absolute permeability of 100 md and a porosity of 18.8%. A core was enclosed with heat-shrink plastic tubing and contained in a stainless-steel pressure bomb. A pressure-controlled pump was used to inject gas and water into the core. Injection pressure was controlled to within 173 kPa of the desired value. Two pressure transducers were used to measure inlet and outlet pressures of the core. The system temperature was maintained at 273.7 K in a liquid bath containing a mixture of equal volumes of water and glycol. The electric resistance was measured with four pairs of electrodes implanted at equal distances along the core under the heat-shrink tubing, as shown in Fig. 14. Measurement of the electric resistances provided an additional method to check for hydrate formation besides the pressure drop in the core sample. A more detailed description of the apparatus is given in Ref. 11.

Experimental Procedure. The core sample is initially evacuated and saturated with 1.5 wt% aqueous NaCl solution. The core is pressurized externally to 1034 kPa higher than the injection pressure (the pressure at which gas and water displacements are performed). Then, several PV's of the brine solution are circulated under high pressure throughout the core to ensure full saturation and stability. Later, gas injection is commenced at a pressure of 7791 kPa and a temperature of 273.7 K. Gas injection is continued until the desired water and gas saturations are achieved in the core. The produced water and gas volumes are closely monitored during this step. The outlet valve is then closed, and gas injection is maintained during the hydrate formation. When no more gas uptake is

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**TABLE 1—MODEL INPUT DATA FOR TESTING AND FITTING**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of blocks</td>
<td>50</td>
</tr>
<tr>
<td>Length of the model, cm</td>
<td>15</td>
</tr>
<tr>
<td>Cross-sectional area, cm²</td>
<td>11.4</td>
</tr>
<tr>
<td>Permeability, md</td>
<td>$10 \times 10^{-6}$</td>
</tr>
<tr>
<td>Temperature, K</td>
<td>274</td>
</tr>
<tr>
<td>Initial pressure, MPa</td>
<td>3.17</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>18.8</td>
</tr>
<tr>
<td>Initial water saturation, %</td>
<td>17.0</td>
</tr>
<tr>
<td>Initial hydrate saturation, %</td>
<td>42.76</td>
</tr>
<tr>
<td>$P_r$, MPa</td>
<td>2.84</td>
</tr>
<tr>
<td>$P_w$, MPa</td>
<td>2.495</td>
</tr>
<tr>
<td>$K_w$, kmol/(m²·Pa·s)</td>
<td>$4.4 \times 10^{-6}$</td>
</tr>
<tr>
<td>$\mu_w$, mPa·s</td>
<td>1</td>
</tr>
<tr>
<td>$c_w$, Pa</td>
<td>$6.9 \times 10^{-6}$</td>
</tr>
<tr>
<td>$\epsilon$</td>
<td>0.001</td>
</tr>
<tr>
<td>$\Delta t$, seconds</td>
<td>0.0125</td>
</tr>
</tbody>
</table>

Fitting the Experimental Data*  
*All properties the same as above with the exceptions listed.

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**Fig. 14**—Electric circuitry of the resistance-measuring device.

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**Fig. 15**—Inlet and outlet pressure behavior during hydrate formation and the annealing process.

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**Fig. 16**—Electric resistance behavior during hydrate formation and the annealing process.

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possible, the inlet valve is closed. At this stage, the bath temperature is maintained at 273.7 K to allow hydrate formation to continue for a period of 5 to 34 hours. When no change in the pressure and the electric resistance with time is observed, the hydrate formation automatically ceases.

In many instances after the hydrate is formed, especially with the lower-permeability cores, a pressure drop of up to 2.8 MPa across the core is detected. One or more cycles of annealing process are performed to eliminate this pressure drop and to ensure more uniform hydrate distribution along the core. In the annealing process, the hydrate is dissociated and reformed by subsequent heating and cooling of the core. The effect of the annealing process on the behavior of the pressure and electric resistance during a typical hydrate formation run is presented in Figs. 15 and 16, respectively. The resistance changes in Fig. 16 show that hydrate formation is not uniform along the core length, causing the permeability to vary. Thus, the permeability is lower at the inlet of the core, where more hydrate is formed.

After hydrate formation, dissociation is commenced at constant outlet pressure and bath temperature. The rate of gas produced during this step is measured by water displacement into a graduated cylinder over 1-minute intervals. The inlet and outlet pressures and the electric resistance along the core are recorded at the same time intervals. The change in the electric resistance during this stage is used to track the dissociation front. At the end of the dissociation process, the water produced during this step is determined.

**Experimental Results and Model Matching**

Figs. 17 and 18 represent the experimental data for the cumulative gas produced and the dissociation-front location, respectively. In both figures, the data are shown as circles and the model fit as a solid line. Total cumulative water produced as predicted by the model was 9.7 cm$^3$, as opposed to 12.8 cm$^3$ measured at the end of the dissociation process. Overall, the agreement between the model predictions and the experimental data is quite satisfactory.

To obtain a satisfactory match of the model to the data, the absolute permeability, relative permeability, and reaction rate constant were varied. The initial absolute permeability varied linearly from $25 \times 10^{-6}$ md at the outlet to $2 \times 10^{-6}$ md in the undissociated-hydrate region. These data have not been measured; however, our experimental observations qualitatively suggest this type of variation.

The relative-permeability/water-saturation curve ($k_{rw}$ vs. $S_w$) was shifted upward about 20% to make the system more permeable to water. The relative permeability curve for gas ($k_{rg}$ vs. $S_w$) was shifted upward 3% to make the system slightly more permeable to gas.

The dissociation reaction rate constant, $k_d$, was decreased from $10^{-11}$ kmol/(m$^2$·Pa·s), as reported by Kim et al. for pure hydrate dissociation, to $10^{-16}$ kmol/(m$^2$·Pa·s). The value reported by Kim et al. was obtained for conditions where mass-transfer resistance was negligible. For hydrate dissociation in porous media, however, we expect the mass-transfer resistance to be substantial, resulting in a lower value of $k_d$. Future work will incorporate the theory of dispersion in porous media to estimate the mass-transfer resistance.

**Conclusions**

1. A three-phase (gas/water/hydrate), 1D numerical model was developed to simulate mathematically the process of isothermal hydrate dissociation in Berea sandstone samples. Depressurization was considered the drive mechanism of hydrate dissociation in porous media.
2. The model differs from previous ones in implementing the kinetics of hydrate dissociation in porous media; the flow of water associated with hydrate dissociation was considered.
3. The experimental and numerical model results showed that an appreciable amount of water is produced simultaneously with gas production as a result of hydrate dissociation in porous media.
4. The mathematical model provided a satisfactory match to the experimental data.

**Nomenclature**

- $A$ = cross-sectional area of the model, m$^2$
- $A_s$ = specific surface area, m$^{-1}$
- $c_w$ = isothermal water compressibility, Pa$^{-1}$
- $f$ = arbitrary function
- $k$ = absolute permeability, md
- $k_d$ = dissociation reaction rate constant, kg/(m$^2$·Pa·s)
- $k_{rg}$ = relative permeability of Phase t
- $L$ = total length of the core, m
- $m_t$ = mass rate per unit volume of Phase t, kg/(m$^3$·s)
- $M_e$ = molecular weight of Component t, kg/kmol
- $n$ = total number of blocks
- $N_H$ = hydrate number, dimensionless
- $P_c$ = capillary pressure, Pa
Majeed H. Yousif

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\[ p_e = \text{equilibrium pressure, Pa} \]
\[ p_l = \text{pressure of Phase } l, \text{ Pa} \]
\[ p_0 = \text{pressure at boundary } x=0, \text{ Pa} \]
\[ S_l = \text{saturation of Phase } l \]
\[ t = \text{time, seconds} \]
\[ \Delta t = \text{time increment, seconds} \]
\[ T = \text{temperature, K} \]
\[ v_l = \text{velocity of Phase } l, \text{ m/s} \]
\[ V = \text{grid volume, m}^3 \]
\[ x = \text{distance, m} \]
\[ \Delta x = \text{distance increment, m} \]
\[ \epsilon = \text{convergence tolerance} \]
\[ \mu_l = \text{viscosity of Phase } l, \text{ Pa} \cdot \text{s} \]
\[ \rho_l = \text{density of Phase } l, \text{ kg/m}^3 \]
\[ \phi = \text{porosity of medium, dimensionless} \]
\[ \phi_{wg} = \text{PV occupied by gas and water per unit volume, dimensionless} \]

Subscripts

\[ \frac{1}{2} = \text{boundary condition } (x=0) \]
\[ n + \frac{1}{2} = \text{boundary condition } (x=L) \]
\[ i = \text{Gridpoint } i \]
\[ i+1 = \text{Gridpoint } i+1 \]
\[ i, j, k = \text{boundaries of a block containing Point } i \]
\[ g = \text{gas} \]
\[ H = \text{hydrate} \]
\[ w = \text{water} \]

Superscripts

\[ n = \text{time level, } n=0, 1, 2, 3 \ldots \]
\[ o = \text{boundary conditions} \]

Operators

\[ \delta_x = \text{difference operator for space derivatives} \]
\[ \delta_t = \text{difference operator for time derivatives} \]
\[ \Delta = \text{difference operator} \]

References


SI Metric Conversion Factors

\[ \begin{align*}
\text{cp} & \times 1.0* \quad \text{E-03} = \text{Pa} \cdot \text{s} \\
\text{ft} & \times 3.048* \quad \text{E-01} = \text{m} \\
\text{ft}^2 & \times 9.290 304* \quad \text{E-02} = \text{m}^2 \\
^\circ\text{F} & \times (^\circ\text{F} + 459.67)/1.8 \quad = \text{K} \\
\text{in.} & \times 2.54* \quad \text{E+00} = \text{cm} \\
\text{in.}^2 & \times 6.451 6* \quad \text{E+00} = \text{cm}^2 \\
\text{lbm mol} & \times 4.535 924 \quad \text{E-01} = \text{kmol} \\
\text{md} & \times 9.869 233 \quad \text{E-04} = \text{m}^2 \\
\text{psi} & \times 6.894 757 \quad \text{E+00} = \text{KPa} \\
\text{R} & = \text{R}/1.8 \quad = \text{K}
\end{align*} \]

*Conversion factor is exact.